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CHEMICAL ENGINEERING | RESEARCH ARTICLE

Implications of Chemical-Thermal enhanced oil recovery methods in shale reservoirs

Huang Jing¹ and Afshin Davarpanah^{2*}

Abstract: Recent advancement in enhanced oil recovery techniques has given petroleum industries the chance to find optimum solutions to recover remained oil from hydrocarbon reservoirs. This paper aims to experimentally investigate the profound impact of reservoir characteristics such as permeability and pressure drop and foams properties such as foam quality and foams resistance factor in enhanced oil recovery processes. Therefore, a hybrid recovery technique containing a thermal recovery method (carbon dioxide) and a chemical method (foam injection) with different brine concentrations was performed to enhance the oil recovery factor. Consequently, after brine injectivity, foam injection has provided the highest recovery factor among other scenarios in shale reservoirs. Permeability increase has caused to increase in the resistance factor as the fluid mobilization is increased in the porous media. Therefore, for 80% of foam quality, the resistance factor is about 7.5, while for 40%, foam quality is about 5 at the permeability of 10mD.

Subjects: Heat Transfer; Thermodynamics; Fluid Mechanics

Keywords: Shale reservoirs; foam injection; carbon dioxide; resistance factor; oil recovery

1. Introduction

Shale reservoirs have required specific recovery methods adapted to the reservoir characteristics (Alvarado & Manrique, 2010; Davarpanah, 2018a; Ebadati et al., 2019b; Mahmoud et al., 2018; Thomas, 2008). These have consisted of oil and gas shales, gas hydrate deposits, tight gas sands, coalbed methane, and heavy oil sands (Davarpanah et al., 2019a, 2018; Haiyan & Davarpanah, 2020; Sahu et al., 2020; Siavashi & Doranehgard, 2017). Due to tight reservoirs' limitations and restrictions, providing sufficient water in water flooding processes has always been a concern

ABOUT THE AUTHOR

Afshin Davarpanah currently works at the Department of Mathematics and Physics, Aberystwyth, United Kingdom. My educational background and training coupled with extensive coursework in mathematical modelling of polymer flooding (which is coupled with the effects of fines migration) and foam flooding, the utilization of Surfactant and foaming agent in the EOR processes, WAG processes in oil recovery enhancement that have improved my materials processing and characterization skills. Further, my current research works at mathematical and numerical modelling of CO₂ sequestration and Geothermal oil reservoirs has enriched my fundamental knowledge of carbon solubility and carbon sequestration.

PUBLIC INTEREST STATEMENT

Recent advancement in enhanced oil recovery techniques has given petroleum industries the chance to find optimum solutions to recover remained oil from hydrocarbon reservoirs. This paper aims to experimentally investigate the profound impact of reservoir characteristics such as permeability and pressure drop and foams properties such as foam quality and foams resistance factor in enhanced oil recovery processes. Therefore, a hybrid recovery technique containing a thermal recovery method (carbon dioxide) and a chemical method (foam injection) with different brine concentrations was performed to enhance the oil recovery factor.

(Davarpanah, 2018b; Q Zhang et al., 2018; Mazarei et al., 2019; Menad et al., 2019a, b; Hu et al., 2020a). Gas recovery methods regarding its feasibility to mobilize through porous media have been preferred in tight reservoirs to enhance oil production (Davarpanah & Mirshekari, 2019a; De Holanda et al., 2018; Omran & Berg, 2020; Tang et al., 2018; Wu et al., 2018). The low permeability of these reservoirs, steam injection, or stimulation treatments would be more economical as more mobility control is required to displace the remaining oil to the production wells (National Energy Board, 2011; Todd & Evans, 2016; Kuang et al., 2018).

Due to the remaining large volumes of oil in the tight reservoirs, oil production would be reduced after one year of primary recovery techniques, and this is why petroleum industries have tried to propose thermal and chemical recovery techniques to produce the remaining oil more efficiently (Davarpanah, 2020; Davarpanah & Mirshekari, 2019b; Ebadati et al., 2019a; Luo et al., 2017; Singh & Cai, 2018; Valizadeh et al., 2019). Chemical recovery techniques have always provided efficient results in oil production. The application of foams in the oil recovery from tight reservoirs by increasing mobility control is shown as a novel method to enhance sweep efficiency (Davarpanah & Mirshekari, 2019c, 2020a; Davarpanah et al., 2019b; Y Hu et al., 2020c; Yu et al., 2019). Moreover, the foaming agent, which is always a surfactant that reduces the interfacial tension between oil and water phases, would increase the oil production rate in tight reservoirs (Davarpanah & Mirshekari, 2020b; Sie & Nguyen, 2019, 2020; Wei et al., 2018; Y Zhang et al., 2019). Alfarge et al. (2017) investigated different experimental and simulation techniques and compared each technique's feasibility to tight reservoirs' oil recovery factor. It is proved that surfactant, carbon dioxide, and natural gas flooding are the most optimum recovery methods to improve sweep efficiency in tight reservoirs (Alfarge et al., 2017). Moreover, they found that due to the misleading of the diffusion mechanism in pilot tests, there are some differences between laboratory and field tests that should be considered in the results. Pankaj et al. (2018) investigated fluid flow behaviour mechanisms in fractured reservoirs in the Eagle Ford oilfield. They proposed a 3D petrophysical and geomechanical model to consider the fluid flow through natural fractures and improve the oil recovery by carbon dioxide injection. They concluded that the CO₂ huff-n-puff technique would be an efficient method as the gas phase can mobilize more through the tight pores and spaces (Pankaj et al., 2018).

Due to the Soltanian et al. (2019) findings, the considerable influence of reservoir characteristics such as permeability and porosity experimentally investigated during carbon dioxide injection in unconventional reservoirs. It can be concluded that permeability has been affected more in carbon dioxide injectivity as the gas phase can be conducted more, especially in tight pores and channels (Soltanian et al., 2019). In this paper, different permeabilities were schematically plotted to compare the resistance factor. Consequently, permeability increase has caused to increase in the resistance factor due to the more mobilization of fluids in porous media. On the other hand, according to the Dashtian et al. (2018) findings, they concluded that pore size distribution is essential in hydrocarbon transport, especially in tight pore networks that are utterly dependent on the reservoir permeability (Dashtian et al., 2018). It is following the permeability effect that is discussed in this paper. Nell experimentally investigated the crucial role of rock wettability in foam flooding performances. They concluded that foams could destabilize the oil phase, improving oil transportation through porous media. In this paper, foam injection after brine injectivity has provided the highest recovery factor among other scenarios in shale reservoirs, under Nell's (2015) findings (Farajzadeh et al., 2012). Hu et al. (2020b) developed a set of experimental investigations to consider the effect of cyclic carbon dioxide injection in different temperatures and pressures in shale reservoirs. They concluded that permeability is a crucial factor in carbon dioxide injection due to gas-phase feasibility through porous media to carry the oil phase out. In this paper, the permeability effect is considered the same findings as Hu et al.'s (2020) paper (Hu et al., 2020b).

Due to the complexity of tight reservoirs, in this paper, different injectivity scenarios were experimentally investigated to consider the profound impact of thermal recovery methods (carbon dioxide) and chemical methods (foam injection) with different brine concentrations to measure

Table 1. Brine compositions

Ion type	Salinity (ppm)
Ca^{2+}	7526.34
Mg^{2+}	153.81
Na^+	4023.16
SO_4^{2-}	54.52
HCO_3^-	223.18
Cl^-	10,115.67
Total Salinity	22,096.68

Table 2. Crude oil composition

Composition	Mole%	Composition	Mole%
C_1	20.14	C_8	3.42
C_2	6.59	C_9	4.13
C_3	5.14	C_{10}	3.84
nC_4	1.25	C_{11}	3.85
iC_4	2.96	C_{12+}	2.4
nC_5	1.54	CO_2	0.84
iC_5	2.36	H_2S	0
C_6	4.52	N_2	0.3
C_7	20.14		

enhance oil recovery factor. Moreover, reservoir characteristics such as permeability, resistance factor, and pressure drop were investigated explicitly to define each parameter's alteration.

2. Materials and methods

2.1. Materials

Core plug; the provided core samples extracted from Pazanan oilfield in the south of Iran with a relatively outer diameter of 4.1 cm and 8.24 cm in length. Core samples permeability was measured in an average value of 0.2–0.4 mD. As cores might be broken during the core flooding processes and the sealing procedure might be time-consuming for each core sample, the total number of cores is 30. This is related to repeating the tests two or three times to remove the experimental errors and obtain an average value for each test.

The brine contains CaCl_2 salt, under the field foam injections procedures from shale reservoirs to be more adapted with the formation brine. The provided brine's salinity is 22,096.68 ppm with a viscosity of 1 cP, a density of 1.05 g/cm^3 , and a pH of 6.25. Brine composition is described explicitly in Table 1.

Crude Oil; density and viscosity of selected crude oil is 0.836 g/cm^3 and 5.49 cP, respectively. The composition of crude oil is described for each composition in Table 2.

Chemical agent; Alpha olefin sulfonate (AOS 40) was used as a surfactant agent to generate foams for flooding processes. This type of surfactant is anionic with a freeze and boiling point of -7°C and 100°C . This condition would be critical as the surfactant can be stabilized as the liquid phase in the laboratory. The viscosity and density of the AOS is 125 cP and 1.05 g/ml. In this study, one wt% of surfactant agents was used to generate foams.

2.2. Core flooding procedure

Before commencing the core flooding tests, all the core samples should be sealed in the core holder at two different pressures on the inlet and outlet. To confine the pressure between the core holder wall and core sleeves, an ISCO syringe pump was used. It also controls the flow injectivity through the system.

The Coreflooding apparatus is schematically depicted in Figure 1. According to Figure 1, the experimental procedure is followed by the sequential steps;

- Core samples dried at the 77 °C for 72 h to measure the porosity and permeability of the Permeameter-Prodrometer device's permeability. Next, they placed it into the core holder under the confining pressure of 2.07 Pa, and then it is vacuumed for about one day to eliminate the air.
- To have a steady-state flow in the core plug, it is saturated with the brine, and the permeability of the liquid phase is determined by the application of Darcy's law in the single-phase situation.
- Crude oil, with a rate of 0.5 mL/min, was injected into the system. This was done to provide 1% water cut.
- Brine with the 0.6 mL/min flow rate was injected into the system to measure residual oil saturation.
- The specified volume of chemical and carbon dioxide is injected into the core samples on the miscible condition at the flow rate of 0.6 mL/min to reach the water cut of 99%. The working pressure for the supercritical carbon dioxide is 1.72 Pa. CO₂ is injected with a temperature of 31 °C to be more adapted to the reservoir temperature under a pressure of about 7 Mpa.

3. Results and discussion

In this part of the study, three injectivity scenarios were investigated to consider each scenario's efficiency in the presence and absence of the oil phase during the flooding procedure. The injectivity scenarios are brine injection, carbon dioxide (CO₂) injection, and foam-CO₂ injection.

Figure 1. Experimental apparatus to consider different injectivity scenarios of foams injection, CO₂ injection after brine injection.

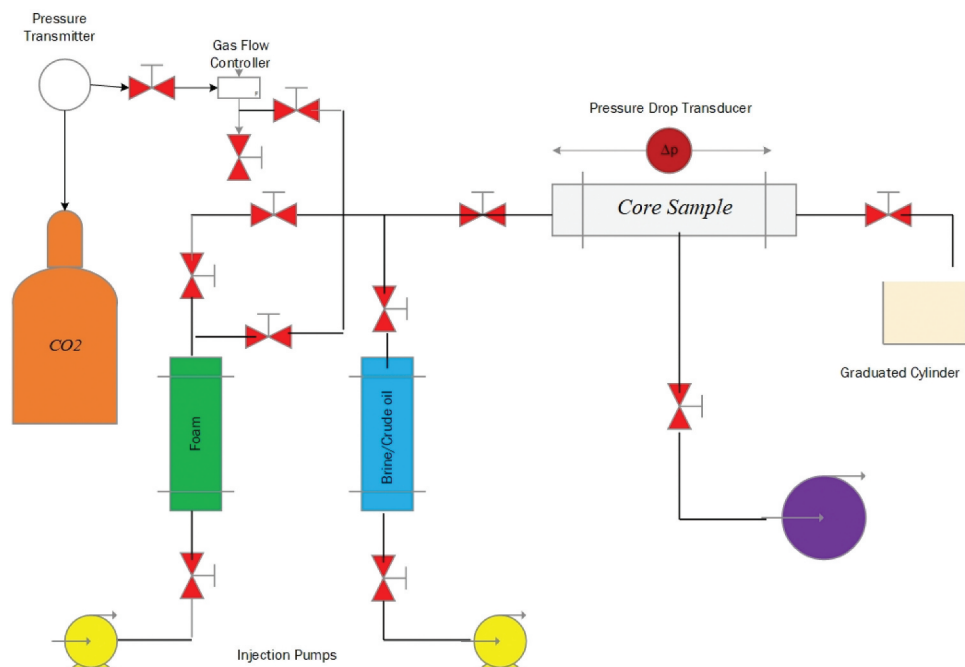


Table 3. Resistance factor for different foam qualities

Test No.	Total Injection	Gas Fraction	Resistance factor
1	0.1	80%	3.76
2	0.1	60%	3.28
3	0.1	40%	2.91
4	0.05	80%	4.95
5	0.05	60%	4.62
6	0.05	40%	4.37

3.1. Resistance factor

Resistance factor is defined as the ratio of foam pressure drop versus brine pressure drop in a steady-state condition. Foam with 80% of foam quality had the maximum resistance factor. In contrast, foam mobility reduction has witnessed the lowest value among other foam qualities. It is caused by the low increment of pressure drop in a steady-state condition. Furthermore, brine and gas coinjection has provided more pressure drop by increasing the total injection rate related to the gas channeling issue and improving the oil recovery. Thereby, foam flooding had the best efficiency rather than brine and gas injection. The value of the resistance factor at various foam qualities is statistically depicted in Table 3. It is concluded that higher foam qualities provide a higher resistance factor. For 80% of foam quality, the resistance factor is about 4.95 and 3.76 at 0.05 and a 0.1 cm³/min injection.

3.2. Pressure drop

The pressure drop for each scenario is different regarding the various performance of each scenario. Pressure drop measurements for each scenario is statistically depicted in Table 2 for different gas fractions. Thereby, the increase in foam quality caused to increase in the foam flooding pressure drop and a decrease in the brine and gas coinjection pressure drop. Moreover, it is concluded that foaming agents (surfactants) significantly increase oil recovery in shale reservoirs. As shown in Table 4, the increase of gas fraction increases caused an increase in brine-CO₂ pressure drop to decrease foam-CO₂ pressure drop. Foams and CO₂ injection has the highest pressure drop of 235 kPa when the foam quality is 80%. By the decrease of foam quality from 80 to 40%, pressure drop has decreased accordingly.

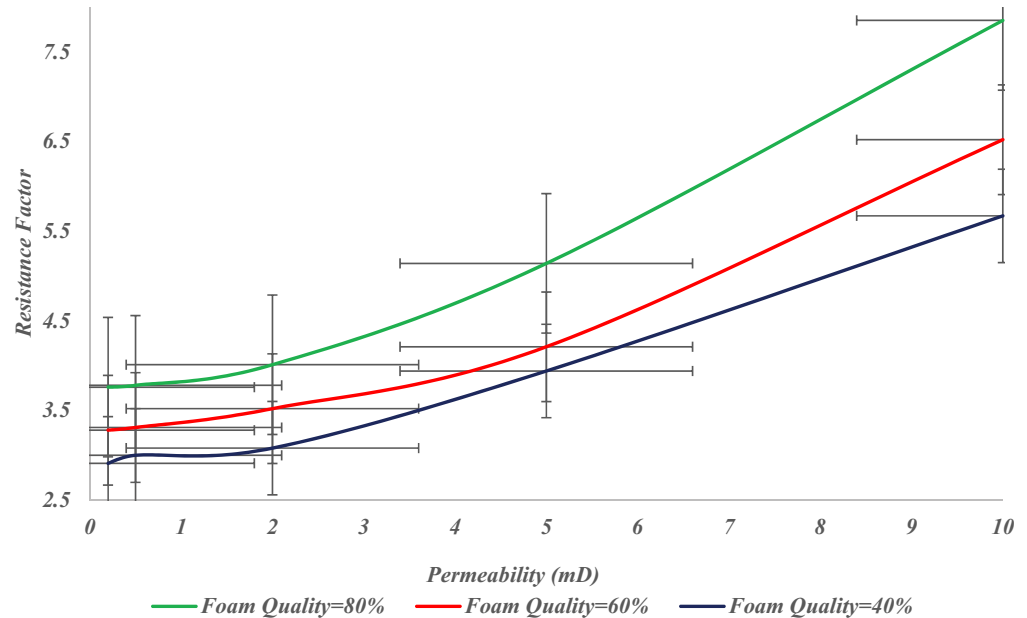
3.3. Permeability impact

Permeability is considered as one of the crucial parameters in porous media that affect recovery performances. This parameter in tight reservoirs is extremely lower than in conventional reservoirs. Thereby, the resistance factor of foam is lower than its value for conventional reservoirs. As

Table 4. Pressure drop measurement for different scenarios at different gas fractions

Test No.	Injectivity Scenario	Gas Fraction	Pressure Drop at steady-state condition, kPa
1	Brine	-	37
2	Brine and CO ₂	80%	44
3	Foam and CO ₂	80%	235
4	Brine and CO ₂	60%	52
5	Foam and CO ₂	60%	204
6	Brine and CO ₂	40%	76
7	Foam and CO ₂	40%	176

Figure 2. Resistance factor versus permeability in tight reservoirs for foam qualities of 80%, 60%, and 40%.



discussed in section 3.1, higher foam quality has provided a higher resistance factor for foam in recovery performances. Therefore, for 80% of foam quality, the resistance factor is about 7.5, while for 40%, foam quality is about 5 at the permeability of 10mD. As can be seen in Figure 2, different permeabilities were schematically plotted to compare the resistance factor. Consequently, permeability increase has caused to increase in the resistance factor due to the more mobilization of fluids in porous media.

3.4. Recovery factor

In this part of the study, each scenario's efficiency was evaluated by the recovery factor, considered one of the critical parameters used to measure the porous media's oil production rate.

Figure 3. Recovery factor measurement for two injectivity scenarios of carbon dioxide and foams injection after brine injection compared with brine injections.

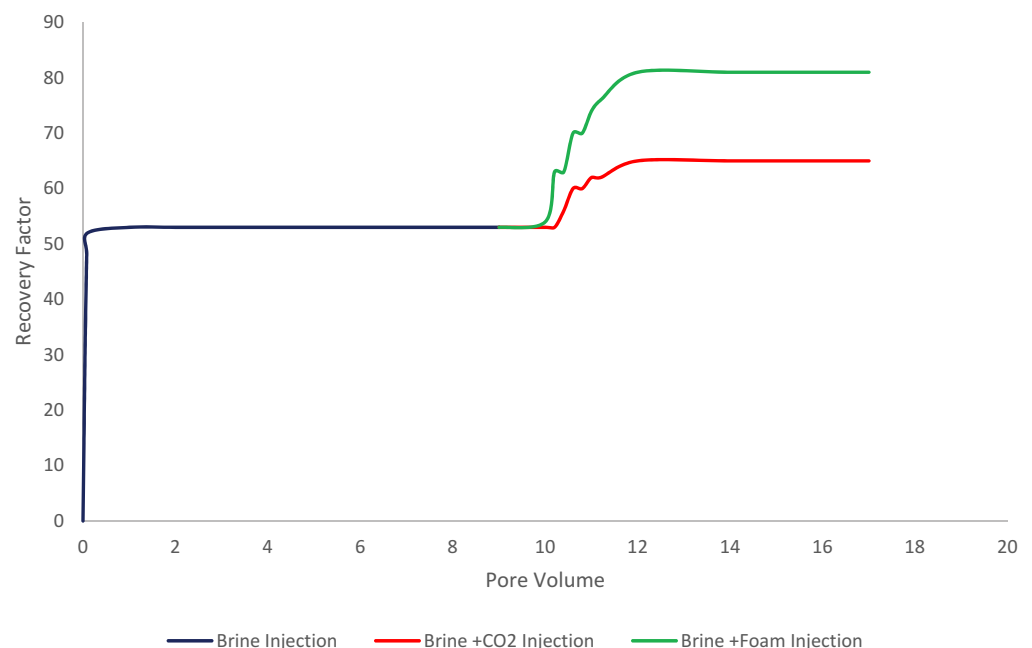


Figure 3 provides the recovery factor for each scenario versus pore volume injection. Figure 3 shows that foam injection after brine injectivity has the highest recovery factor among other shale reservoir scenarios.

4. Conclusion

As shale reservoirs are considered as one of the unconventional reservoirs in the world and production from these reservoirs is more complicated than conventional reservoirs, in this study, the combination of thermal methods (carbon dioxide and nitrogen injection) and chemical methods (foam injection) with different brine concentrations to measure enhance oil recovery factor. Therefore, after brine injectivity, foam injection has provided the highest recovery factor among other scenarios in shale reservoirs. Permeability increase has caused to increase in the resistance factor due to the more mobilization of fluids in porous media.

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Disclosure statement

The author(s) declare that they have no conflict of interest.

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